THE ROLE OF CORE ANALYSIS DATA IN THE SYSTEMATIC AND DETAILED MODELING OF FRACTURED CARBONATE RESERVOIR PETROPHYSICAL PROPERTIES TO REDUCE UNCERTAINTY IN RESERVOIR SIMULATION

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ABSTRACT

A great number of the most prolific oil reservoirs in the Mexico part of the Gulf of Mexico are fractured Carbonate systems. Dynamic modeling of these types of reservoir systems poses a great deal of challenges to reservoir engineers. This is particularly true if the petrophysical characterization is not properly done. Many times, the same princinples designed for petrophysical evaluation of sandstone reservoir systems have been erroneously applied to carbonate systems. The aim of this paper is to demonstrate the inefficacy of such approach and present a systematic methodology that has been proven effective and some results of its successful application.

The key to unlock the hydrocarbon potential of a naturally fractured reservoir is to evaluate its static hydrocarbon content through accurate determination of water saturation, and predict its dynamic flow capacity through estimation of porosity and permeability. The characterization should be performed both in the matrix and the fractures systems using core calibrated wireline data. This technique is quite simple. It is based upon deriving formation resistivity factor, tortuosity, partitioning coefficient, fracture intensity index, matrix porosity, fracture porosity, and fracture storativity ratio for naturally fractured formation in terms of total porosity, and cementation exponent, m, only. The technique includes characterizing the various hydraulic (flow) units in heterogeneous naturally fractured reservoirs using full diameter core analysis data where available or data from core plugs sampled in the fractured zone. When data from core plugs are used, it is necessary to have enough data to achieve statistical significance. The Hydraulic units concept enables us to determine how the reservoir quality changes with fracture intensity and distribution, which manifest in terms or tortuosity of formation resistivity factor.

In the conceptual examples presented in this paper, series of petrophysical cross plot was used in conjunction with the variable “m” to identify porosity types. This process combined with the fractured hydraulic units zonation was used for the petrophysical characterization of the carbonate system. A comparison of the petrophysical parameters obtained from this more rigorous method with previous interpretation shows a remarkable improvement. We also demonstrate in this paper that seismic attribute correlates very well with petrophysical attributes if the petrophysical parameters are

correctly determined and are representative of the rock system. The improvement in the static and dynamic models based on proper petrophysical modeling is demonstrated.

INTRODUCTION

Carbonate reservoir systems typically are made up of different lithology and porosity types. In the Gulf of Mexico the most sought after porosity types in carbonate is the fracture porosity. Naturally fractured reservoirs may be composed of any lithology including clastics (sands or shales), carbonates, and even basement rocks. However, they are more pronounced and attractive in carbonates. Several investigators have attempted to evaluate naturally fractured reservoirs using various methods ranging from the macroscopic scale of core analysis through the mesoscopic scale of well logging up to the megascopic scale of pressure transient analysis and 3-D seismic. Each of those methods has certain advantages, limitations, applicability and reliability.[1]

Reservoir engineers must understand the flow behavior of naturally fractured reservoir, as this is the key for effective prediction of productivity, reserves and recovery of hydrocarbon. The key to this understanding and the evaluation of the hydrocarbon potential of a naturally fractured reservoir is to (1) evaluate hydrocarbon content through accurate determination of porosities and fluid saturation, and (2) predict its dynamic flow capacity through proper estimation of permeabilities. This needs to be done in the matrix and the fractures systems at the reservoir or simulated reservoir conditions.

Naturally fractured reservoirs are found in various rock types, including carbonates, sandstones, siltstones, shales, cherts and basement rocks. The percentage of the matrix-fracture systems, i.e. total porosity, attributed to fractures ranges from very small to 100 percent. Four types of naturally fractured reservoirs can be identified[2] based on the extent the fractures have altered the reservoir matrix porosity and permeability. In Type 1 reservoirs, fractures provide all of the storage capacity and permeability. In Type 2 naturally fractured reservoirs, the matrix has negligible permeability but contains most if not all the hydrocarbons. The fractures provide the essential reservoir permeability. In Type 3 reservoirs, the matrix has an already good primary permeability. The fractures add to the reservoir permeability and can result in considerable high flow rates. Oil is trapped in both the matrix and fractures. In Type 4 reservoirs, the fractures are filled with minerals. Fractures provide no additional porosity or permeability but create a significant reservoir.

In a given reservoir, there can be more than one family of fractures, and it is important to recognize their origin, size and scale. This is because they do not exhibit the same petrophysical and rheological characteristics. For example, micro fissures arising from cooling crystalline formations are not as areally extensive as tectonically induced fractures. The former may exhibit random permeability pattern, whereas the latter may exhibit a permeability anisotropy conditioned by the principal stress originated from the tectonic history of the environment. Hence, any petrophysical interpretation should include a detailed description of the fracture width, aperture, orientation and scale.

The evaluation and modeling approaches depend on the type of fracture, their size and scale, as well as stress dependency as describe above. Both the permeability and porosity of the fracture and the matrix can be key parameter in reservoir simulation models used to predict performance of any of the above mentioned fractured reservoir type. Methods of evaluating naturally fractured reservoir petrophysically depend on data from cores, wireline logs, pressure transient well test analysis and a combination of all three. Typically, well logs and reservoir condition core analysis data both provide *in-situ* data and possess higher resolution compared to well testing techniques. In reservoir engineering modeling in non-homogeneous reservoirs where permeability and porosity profiles are extremely important, more importance should be placed in core analysis calibrated log analysis data. This information needs to be upscaled and compared to pressure transient analysis data for reason of calibration.

REVIEW OF TECHNIQUES FOR EVALUATION

In the following section, we present a brief review of some techniques for evaluating naturally fractured reservoir rocks.

Core Analysis

The most direct and reliable method to determine reservoir rock properties is to obtain a core sample from the zone of interest and perform laboratory analysis. However, for naturally fractured reservoir, traditional methods that provide reliable results in non-fractured rock are not applicable. The literature abounds with a lot of publications describing modifications to traditional methods to handle the special requirements for naturally fractured systems. Other non-conventional methods like thin microscopy, computerized tomographic scanning and fluoresce epoxy impregnation,[2] NMR imaging, etc have also been described in the literature.

The difficulties in the conventional methods of core analysis include: (1) Inability to obtain a representative plug samples typically because of the fractured condition of the core, (2) Inability to measure fracture porosity and permeability on plug sample even when they are obtained. For these reasons the core analysis industry has resorted to using full diameter rather than plug samples of core material[3] Methodologies to obtain accurate matrix and fracture porosities and permeabilities are critical. It has been demonstrated[3] that Boyle's Law Helium porosimetry, thin section microscopy and displacement test may not be able to distinguish matrix from fractured porosity and permeability. Two methods were presented for porosity and one method for permeability measurement in naturally fractured rocks. The two porosity methods are Computerize Tomographic scanning and fluorescent epoxy impregnation of full diameter cores at overburden conditions. The permeability methodology presented is a modification to the 3-directional full diameter permeability measurements[4] (API RP 40). This modification is referred to as multi-directional permeameter and has capability to measure permeability in multiple directions. Ning and Holditch presented a unique methodology to predict fracture and matrix properties of naturally fractured tight rock samples[5]. The Ning and Holditch[5] method is based on the behavior of pressure pulse in fracture and in matrix.

Profile permeameter that is capable of measuring permeability in a very fine grid on a slabbed core has been described[6]. The major advantage of this instrument in evaluating naturally fractured rock is the ability to measure the permeability, as the fracture is approached and away from the fracture. The disadvantage is that measurements are done at laboratory condition. This can however be overcome by calibrating to a few full diameter measurements.

Log Analysis

Naturally fractured carbonate reservoirs can also be evaluated using well logging techniques. Several methods are available to evaluate natural and induced fractures in the reservoir from well log data.[7]. For example fracture and vuggy effects on porosity reflect on the measured total porosity from neutron, acoustic and density tools. The effect is also reflected in the cementation exponent, “m”, which represents the tortuosity of the reservoir rock. Usually the value of “m” is approximately equal to 2.0 for formations with interparticle (grains or crystals) porosity and the value for a plane fracture is technically equals 1.0. This is based on the relationship between formation resistivity factor, F, tortuosity, τ, porosity, φ, and the cementation exponent, m. These factors form the basis of our proposed methodology as shown in the sections that follows.

Proposed Methodology

Typically, most naturally fractured carbonate systems are composed of other pore types including fractures, vugs, bimodal and intercrystalline. It is therefore important to review sedimentological and petrological study done on representative cores, sidewalls and cuttings. An example of such description for a carbonate reservoir rock system in the Gulf of Mexico is shown in Figure 1. This sedimentological data acts as a guide in the use of petrophysical cross plots to identify the pore types.

Determination of Pore Types From Series of Cross-Plots

To determine the pore types in the well, series of cross plots are typically performed to identify bimodal porosity, fracture porosity, vuggy porosity, intercrystaline porosity, etc[7]. The following plots are needed for proper identification and differentiation:

1. Sonic versus total porosity (Neutron)
2. MSFL Porosity versus total porosity (neutron)
3. Archie water saturation (n=2, m=2, a=1) versus ratio water saturation

The plots should look like figure 2.

Modeling Approach

The relationship between cementation exponent and tortuosity is given by equation 1 below.

$$F = \frac{R_o}{R_w} = \frac{t}{j} = \frac{1}{j^{m}} \qquad (1)$$

For plane fracture with tortuosity approximately equal to 1 it is easy to see that m is equal to 1. However, fractures are not plane and hence "m" can vary from one (1) up to depending on (1) the intensity of fracturing and tortuosity (2) the relationship between fracture, vugs and matrix (3) Degree of mineralization (m>2 if fracture contains clay minerals). In applying this modeling concept, it is important to note that in addition to tortuosity, cementation exponent depends on (1) Specific surface area, (2) Grain shape (3) Degree of Cementation (4) Clay content and location and (5) Level of pore interconnectivity.

Variable "m" Model

An important aspect in this modeling is the ability to determine variable cementation exponent "m". The technique is described below. The first step is to determine the variation of reservoir rock quality with "m" or hence degree of fracture. For this permeability and porosity measurements as well as formation factors should be measured on a series of fractured full diameter cores representing the reservoir of interest. These measurements are made at simulated reservoir condition using the methods described earlier. As shown in Figure 3, an example of a carbonate reservoir in the Gulf of Mexico, core analysis data on fractured rock samples shows "m" varies from a low of 1.4 in the fractured zone to a high of 2.43 in the mineralized fracture or vuggy zones. This figure also shows that "m" is related to the reservoir quality and that fractures and fracture intensity control reservoir flow capacity.

The "m" can also be estimated from log data. The following relationships and logic are used to estimate variable "m" from logs and to account for the variable pore types (Fracture, Bi-modal, Vuggy and Intercrystaline):

$$m = \frac{LOG\left(\dfrac{R_W(T)}{R_t \times SW_R^2}\right)}{LOG(f_e)} \tag{2}$$

Where

$$SW_R = \left(\frac{R_{xo}/R_t}{R_{mf}/R_w}\right)^{5/8} \tag{3}$$

<u>The Logic</u>

Pore types can be recognized as follows:

m= $2 \pm e$, Pore Type is Intercrysalline

m>2, Pore Type is Vuggy

m< 2, Pore Type is fractured or bi-modal

m< 2, and $\Phi_{RXO} > \Phi_T \pm e$, Pore B-modal

m< 2, and $\Phi_{RXO} < \Phi_T \pm e$, Pore Fracture

Where, $\pm e$ is some tolerance based on random errors.

Flow Properties Determination

Core data may also used to develop equations for fractured reservoir flow properties modeling. From Tiab, et al.[8], for a naturally fractured or vuggy reservoir system, permeability is given as a function of total porosity, specific surface area and "m" as follows:

$$K = \frac{1}{s_{gv}^{2}F_{s}} \frac{f_{t}^{2m+1}}{(1-f_{t})^{2}} \tag{4}$$

Therefore following the hydraulic (Flow) units (HU) concept[9,10,11], we can define RQI for fractured systems as

$$\mathrm{FRQI} = 0.0314\sqrt{\frac{\mathrm{K}}{f_{t}^{2m-1}}} \tag{5}$$

Hence Flow zone indicator for fractured system is defined as

$$\mathrm{FRZI} = \frac{1}{s_{gv}\sqrt{F_{s}}} \tag{6}$$

Hence

$$\log(FRQI) = \log(FRZI) + \log(f_{z}) \tag{7}$$

Where, the porosity group or normalized porosity is defined as $\phi_z=\phi/(1-\phi)$

Note that FRZI is independent of the tortuosity rather than surface to volume ratio. Therefore, as in the HU concept for sandstone, a plot of FRQI versus Φ_z on a log-log paper will delineate the flow units as shown in Figure 4. This information can then be used for log analysis in two ways, namely, System Response Analysis and Flow Zone Assignment based Calculated "m".

1. Systems Response Analysis

This method is the best technique when large amounts of core analysis and log data are available. First a relationship is developed between FRQI and "m" from the representative core measurements. Such a relationship should look as in Figure 3. The second and most important step in the systems response model is the development of training equations or model to determine FRZI from log signatures based on core-log integration. Three different methods are currently available to us for performing this task (1) probabilistic method (2) Neural Network or Fuzzy Logic method and (3) deterministic method (non-linear optimization or generic algorithms).

2. Flow Zone Assignment based on Calculated "m"

This technique is used when available core data is not enough to perform the systems response analysis. From the limited core analysis data, average values of FRZI can be assigned to a range of "m" as shown later in the example. For the application of this methodology in log analysis, "m" is obtained from logs by Eqs. 2 and 3. Once FRZI_{ave} is obtained by either method, permeability can be calculated as follows.

$$K = 1014\ FRZI_{ave}^{2} \frac{\varphi_t^{2m+1}}{(1-\varphi_t)^2} \qquad (8)$$

Differentiating Between Matrix and Fracture Properties

Fracture Porosity

We used the following two concepts to characterize naturally fractured reservoirs: (1) the concept of partitioning coefficient, ν, and (2) the concept of fracture intensity index, FII.

Concept of Partitioning Coefficient, ν.

Partitioning coefficient, ν, represents the allocation of total porosity, φ_t, between matrix porosity, φ_{ma}, and the larger pores (vugs, fissures, fractures, φ_f, etc.) and is given by:

$$\nu = \frac{\varphi_t - \varphi_{ma}}{\varphi_t(1-\varphi_{ma})} \qquad (9)$$

Fracture Intensity Index, FII.

FII represents the magnitude of formation porosity attributed to fractures as the ratio between secondary porosity (fractures) to the solid rock volume as:

$$FII = \frac{\varphi_t - \varphi_{ma}}{1-\varphi_{ma}} \qquad (10)$$

Example from the Gulf of Mexico

In this example of a carbonate reservoir system from Gulf of Campeche, there was limited core data hence the flow zone assignment technique was used. From the limited core data the following four flow zones were identified as shown in Figure 4.

Zone #1

$“m” \le 1.65$, $FRZI_{ave}=89$ (11)

Zone #2

$1.65<“m” \le 1.93$, $FRZI_{ave}=35.6$ (12)

Zone #3

$1.93<“m” \le 2.3$, $FRZI_{ave}=14.24$ (13)

Zone #4

$“m”>2.3$, $FRZI_{ave}=7.85$ (14)

Using Eqs. 3 and 4, “m” values were estimated for all the wells and the range of “m” was used to assign FRZIave according to Eqs. 11-14. Zone 1 is considered a high conductivity fractured zone, zone 2 is dominated by fractures and vugs while zones 3 and 4 have mostly matrix permeability.

This logic was used to determine the matrix and fracture permeability in this project. Note that permeability associated with the zones of interest in seventeen well are sorted as fractured permeability. As shown in Figure 5, the averaged total permeability per well is about two orders of magnitude less than the fractured permeability obtained using the method described in this work. Figure 6 shows the porosity types that exist in each well.

CONCLUSIONS

A systematic methodology to petrophysical evaluation of fractured reservoirs is presented. The benefits of this methodology may be summarized as follows:

- The Hydraulic units concept enables us to determine how the reservoir quality changes with fracture intensity and distribution, which manifest in terms or tortuosity of formation resistivity factor.
- A comparison of the petrophysical parameter obtained from this more rigorous method with previous interpretation shows a remarkable improvement.
- This technique makes upscaling/downscaling of petrophysical data easier and more representative.

NOMENCLATURE

F = formation resistivity factor
τ = tortuosity
φ = porosity
m = cementation exponent
Ro = resistivity of a 100% water saturated rock
Rw = formation water resistivity
R_t = true formation resistivity
ϕ_e = effective porosity
R_{mf} = mud filtrate resistivity
R_{xo} = resistivity of the mud-invaded zone
Φ_{RXO} = porosity of the mud-invaded zone
Φ_T = total porosity
K = permeability
Sgv = grain specific surface area
F_s = pore throat shape factor
FRQI = reservoir quality index for fractured rock system.
FRZI = flow zone index for fractured rock system.
σ = inter matrix-fracture transfer term
L = matrix block length
w = fracture width

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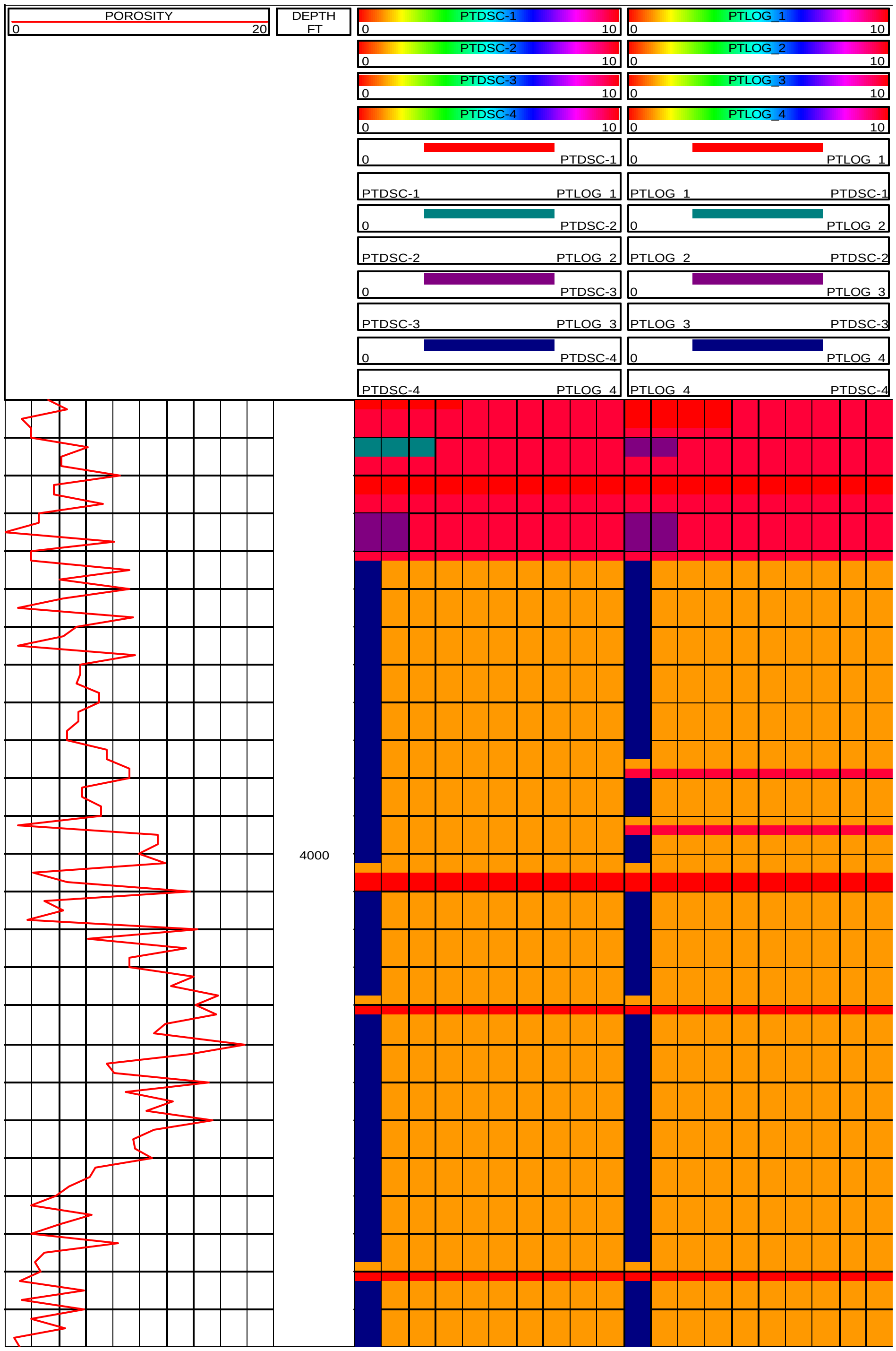

Figure 1. Pore Types in Naturally Fractured Carbonate System – An Example.

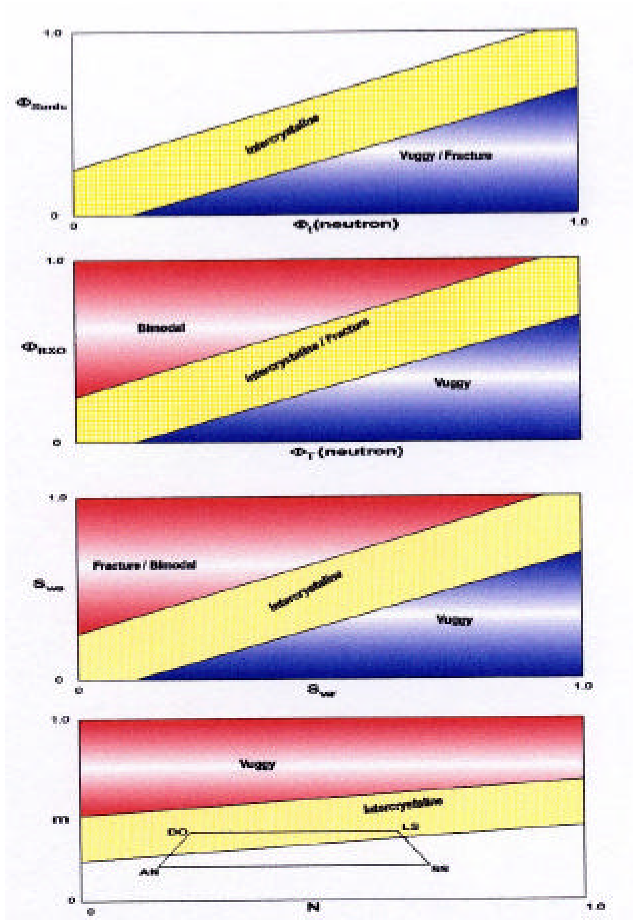

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Figure 2. Fractures and fracture intensity control reservoir flow capacity.

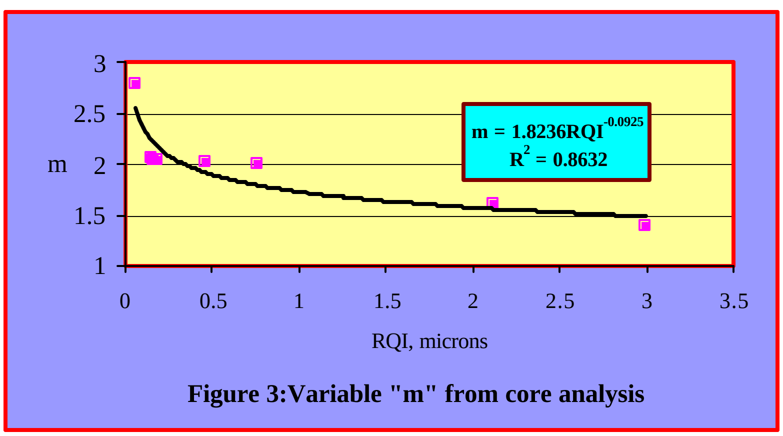

Figure 3:Variable "m" from core analysis

Note:
+ N and m in the M-N plot of Figure 2 are the slopes of the individual lithology lines on the density-neutron and Sonic-density crossplot charts, respectively.

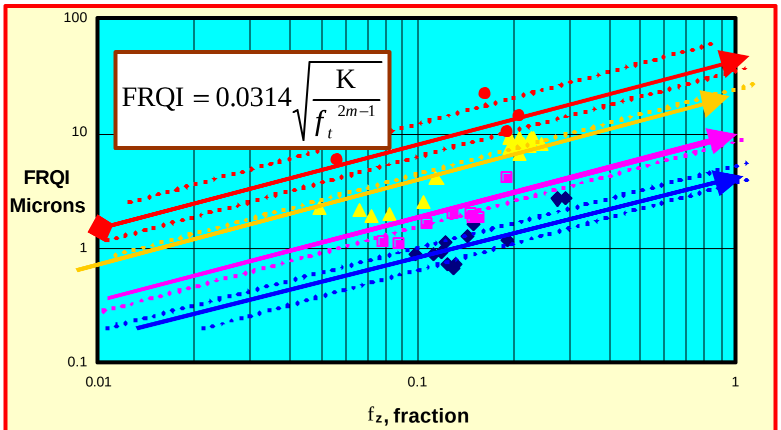

Figure 4: Fracture Flow Units Zonation

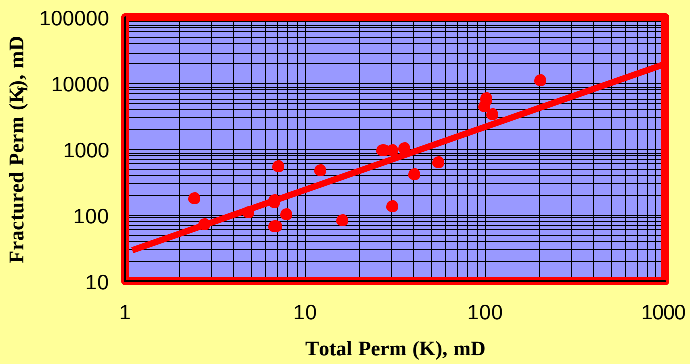

Figure 5: Relationship Between Total Permeability and Fractured Permeability (K_f from fractured zones 1 and 2)

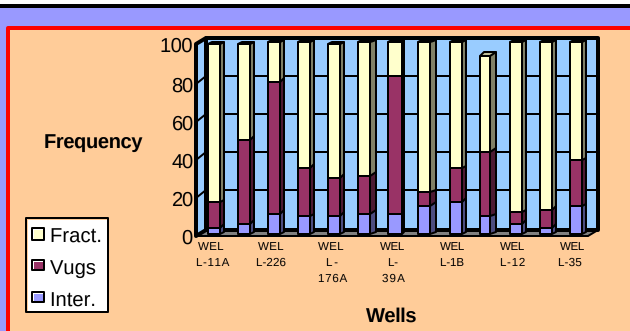

Figure 6: Porosity Types by Wells